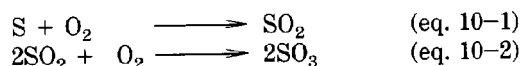


CHAPTER 10

SULFUR OXIDE (SO_x) CONTROL SYSTEMS

10-1. Formation of sulfur oxides (SO_x)

a. Definition of sulfur oxide. All fossil fuels contain sulfur compounds, usually less than 8 percent of the fuel content by weight. During combustion, fuel-bound sulfur is converted to sulfur oxides in much the same way as carbon is oxidized to CO₂. Sulfur dioxide (SO₂) and sulfur trioxide (SO₃) are the predominant sulfur oxides formed. See equations 10-1 and 10-2.



b. Stack-gas concentrations. In efficient fuel combustion processes, approximately 95 percent of the fuel-bound sulfur is oxidized to sulfur dioxide with 1 to 2% being converted to sulfur trioxide.

c. Factors affecting the formation of SO_x.

- (1) SO₂ formation increases as flame temperature increases. Above 3,150 degrees Fahrenheit, SO₂ formation no longer increases.
- (2) SO₃ formation increases as the excess air rate is increased.
- (3) SO₃ formation decreases with coarser atomization.

10-2. Available methods for reducing SO_x emissions

a. Fuel substitution. Burning low sulfur fuel is the most direct means of preventing a SO_x emissions problem. However, low sulfur fuel reserves are decreasing and are not available in many areas. Because of this, fuel cleaning technology has received much attention. There are presently more than 500 coal cleaning plants in this country. At present, more than 20% of the coal consumed yearly by the utility industry is cleaned. Forty to ninety percent of the sulfur in coal can be removed by physical cleaning, depending upon the type of sulfur deposits in the coal. As fuel cleaning technology progresses and the costs of cleaning decrease, fuel cleaning will become a long term solution available for reducing sulfur oxide emissions.

b. Considerations of fuel substitution. Fuel substitution may involve choosing a higher quality fuel grade; or it may mean changing to an alternate fuel type. Fuel substitution may require any of the following considerations:

- (1) Alternations in fuel storage, handling, preparation, and combustion equipment.
- (2) When changing fuel type, such as oil to coal, a new system must be installed.

- (3) When choosing a higher quality fuel, as in changing from residual to distillate fuel oil, modest modifications, such as changing burner tips, and oil feed pumps, are required.

c. Changes in fuel properties. Consideration of possible differences in fuel properties is important. Some examples are:

- (1) Higher ash content increases particulate emissions.
- (2) Lower coal sulfur content decreases ash fusion temperature and enhances boiler tube slagging.
- (3) Lower coal sulfur content increases fly-ash resistivity and adversely affects electrostatic precipitator performance.
- (4) Low sulfur coal types may have higher sodium content which enhances fouling of boiler convection tube surfaces.
- (5) The combination of physical coal cleaning and partial flue gas desulfurization enables many generating stations to meet SO₂ standards at less expense than using flue gas desulfurization alone.

d. Modification of fuel. Some possibilities are:

- (1) Fuels of varying sulfur content may be mixed to adjust the level of sulfur in the fuel to a low enough level to reduce SO₂ emissions to an acceptable level.
- (2) Fuels resulting from these processes will become available in the not too distant future. Gasification of coal removes essentially all of the sulfur and liquification of coal results in a reduction of more than 85% of the sulfur.

e. Applicability of boiler conversion from one fuel type to another. Table 10-1 indicates that most boilers can be converted to other type of firing but that policies of the agencies must also be a consideration.

Table 10-1

Convertibility of steam boilers

As designed			Convertible to:		
Coal	Oil	Gas	Coal	Oil	Gas
**X	X	—	—	—	yes
**X	—	X	—	yes	—
**X	—	—	—	yes	yes
—	X	—	*possible	—	yes
—	—	X	*possible	yes	—

Note: * Large DOD boilers must be convertible to coal firing.

** Changing from coal to oil or gas firing is not in accordance with present AR 420-49.

f. Approach to fuel substitution. An approach to fuel substitution should proceed in the following manner:

- (1) Determine the availability of low sulfur fuels.
- (2) For each, determine which would have sulfur emissions allowable under appropriate regulations.
- (3) Determine the effect of each on particulate emissions, boiler capacity and gas temperatures, boiler fouling and slagging, and existing particulate control devices.
- (4) Identify the required equipment modifications, including transport, storage, handling, preparation, combustion, and control equipment.
- (5) For the required heat output calculate the appropriate fuel feed rate.
- (6) Determine fuel costs.
- (7) Determine the cost of boiler and equipment modification in terms of capital investment and operation.
- (8) Annualize fuel costs, capital charges, and operating and maintenance costs.
- (9) With the original fuel as a baseline, compare emissions and costs for alternate fuels.

(g. Modification to boiler operations and maintenance.

- (1) A method of reducing sulfur oxides emissions is to improve the boiler use of the available heat. If the useful energy release from the boiler per unit of energy input to the boiler can be increased, the total fuel consumption and emissions will also be reduced.
- (2) An improvement in the boiler release of useful energy per unit of energy input can be achieved by increasing boiler steam pressure and temperature. Doubling the steam drum pressure can increase the useful heat release per unit of energy input by seven percent. Increasing the steam temperature from 900 to 1000 degrees Fahrenheit can result in an improvement in the heat release per unit of energy input of about 3.5 percent.
- (3) Another way to maximize the boiler's output per unit of energy input is to increase the attention given to maintenance of the correct fuel to air ratio. Proper automatic controls can perform this function with a high degree of accuracy.
- (4) If additional emphasis can be put on maintenance tasks which directly effect the boilers ability to release more energy per unit of energy input they should be considered a modification of boiler operations. Items which fall into this category are:
 - Washing turbine blades
 - adjusting for maximum throttle pressure

- adjusting turbine control valves to insure proper lift
- adjusting preheater seals and feedwater heaters
- insuring cleanliness of heat transfer surfaces, such as condensers, superheaters, reheaters, and air heaters.

h. Limestone injection. One of the earliest techniques used to reduce sulfur oxide emission was the use of limestone as a fuel additive. This technique involves limestone injection into the boiler with the coal or into the high temperature zone of the furnace. The limestone is calcined by the heat and reacts with the SO₂ in the boiler to form calcium sulfate. The unreacted limestone, and the fly ash are then collected in an electrostatic precipitator, fabric bag filter, or other particulate control device. There are a number of problems associated with this approach:

- (1) The sulfur oxide removal efficiency of the additive approach is in the range of 50 to 70% in field applications. However, it is considered feasible that when combined with coal cleaning, it is possible to achieve an overall SO₂ reduction of 80 percent.
- (2) The limestone used in the process cannot be recovered.
- (3) The addition of limestone increases particulate loadings. In the precipitator this adversely affects collection efficiency.
- (4) The effects of an increased ash load on slagging and fouling as well as on particulate collection equipment present a group of problems which must be carefully considered.
- (5) The high particulate loadings and potential boiler tube fouling in high heat release boilers tend to cause additional expense and technical problems associated with handling large particulate loadings in the collection equipment.
- (6) There have been many claims over the years regarding the applicability of fuel additives to the reduction of sulfur oxide emissions. The United States Environmental Protection Agency has tested the effect of additives on residual and distillate oil-fired furnaces. They conclude that the additives have little or no effect.

i. Flue gas desulfurization (FGD). There are a variety of processes which have demonstrated the ability to remove sulfur oxides from exhaust gases. Although this technology has been demonstrated for some time, its reduction to sound engineering practice and widespread acceptance has been slow. This is particularly true from the standpoint of high system reliability. The most promising systems and their performance characteristics are shown in table 10-2.

j. Boiler injection of limestone with wet scrubber. In this system limestone is injected into the boiler and is

PERFORMANCE CHARACTERISTICS OF FLUE-GAS DESULFURIZATION						
System Type	SO ₂ Removal Efficiency (%)	Pressure Drop (inches of water)	Regeneration and Reliability	Operational Reliability	Retrofit to Existing Installation	Advantages
1) Limestone, boiler injection type	30-40%	less than 6"	no recovery of lime-stone	High	Yes	high reliability
2) Limestone, Scrubber injection type	30-40%	greater than 6"	no recovery of lime	High	Yes	high reliability no boiler scaling
3) Lime, Scrubber injection type	90%	greater than 6"	no recovery of lime	Low	Yes	high efficiency, no boiler scaling, less scaling to scrubber than limestone in some cases
4) Magnesium Oxide	90%	greater than 6"	recovery of Hg and sulfuric acid	Low	Yes	high efficiency; no solids disposal
5) Wellman-Lord	90%	greater than 6"	recovery of NaSO ₃ and sulfur	Unknown	Yes	high efficiency, little scaling
6) Catalytic Oxidation	45%	may be as high as 24"	recovery of H ₂ SO ₄	Unknown	No	high efficiency; no solids disposal problem; catalyst regeneration not necessary
7) Single Alkali Systems	90%	Tray tower pressure drop 1.6-2.0 in. H ₂ O/tray with Venturi added 10-14 in. H ₂ O	little recovery of sodium	Unknown	Yes	high efficiency; reduces scaling and plugging of scrubber
8) Dual alkali Systems	90-95%		Regeneration of sodium hydroxide and sodium sulfites	Unknown	Yes	absorption efficiency potentially higher than other systems; scaling problems reduced; produces solid rather than liquid waste.
9) Dry, post furnace limestone injection	70-80%	Greater than 6"	No recovery of limestone	High	Yes	reduced water consumption lower capital cost simplicity
10) Dry furnace injection of LIMESTONE	40-70%	Less than 6"	No recovery of limestone	High	Yes	reduced water consumption lower capital costs simplicity
						Disadvantages
						low efficiency, scaling in boiler and scrubber, small units only, solids disposal to landfill
						low efficiency, scaling and plugging of nozzles and surfaces in scrubber solids disposal.
						low reliability; solids disposal to landfill
						low reliability; corrosion and erosion of scrubber and piping. Need pre-cleaning of flue gas.
						unknown reliability; need natural gas for SO ₂ Reduction.
						Vanadium pentoxide needed as catalyst; high pressure drop system; unknown reliability; need pre-cleaning of flue gas by high efficiency device.
						throwaway process; chemical coats high when burning high sulfur fuels; disposal of sodium salts; high water makeup rate.
						solids buildup in reactor system; problems with de-watering system.
						most suitable for low and medium sulfur coals.
						increased ash load on particulate collection equipment.

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calcined to lime. The lime reacts with the SO_2 present in the combustion gases to form calcium sulfate and calcium sulfite. As the gas passes through a wet scrubber, the limestone, lime, and reacted lime are washed with water to form sulfite. As the gas passes through a wet scrubber, the limestone, lime, and reacted lime are washed with water to form a slurry. The resulting effluent is sent to a settling pond and the sediment is disposed by landfilling. Removal efficiencies are below 50% but can be reliably maintained. Scaling of boiler tube surfaces is a major problem.

k. *Scrubber injection of limestone.* In this FGD system limestone is injected into a scrubber with water to form a slurry (5 to 15% solids by weight). The limestone is ground into fines so that 85% passes through a 200-mesh screen. CaCO_3 absorbs SO_2 in the scrubber and in a reaction tank where additional time is allowed to complete the reaction. Makeup is added to the reusable slurry as necessary and the mixture is recirculated to the scrubber. The dischargable slurry is taken to a thickener where the solids are precipitated and the water is recirculated to the scrubber. Limestone scrubbing is a throwaway process and sludge disposal may be a problem. At SO_2 removal efficiencies of about 30%, performance data indicate that limestone scrubbers have a 90% operational reliability. Plugging of the demister, and corrosion and erosion of stack gas reheat tubes have been major problems in limestone scrubbers. Figure 10-1 shows a simplified process flow-sheet for a typical limestone scrubbing installation.

l. *Scrubber injection of lime.* This FGD process is similar to the limestone scrubber process, except that lime (Ca(OH)_2) is used as the absorbent. Lime is a more effective reactant than limestone so that less of it is required for the same SO_2 removal efficiency. The decision to use one system over the other is not clear-cut and usually is decided by availability.

m. *Post furnace limestone injection with spray drying.* In this system, a limestone slurry is injected into a spray dryer which receives flue gas directly from the boiler. The limestone in the slurry reacts with the SO_2 present in the combustion gases to form calcium sulfate and calcium sulfite. The heat content of the combustion gases drives off the moisture resulting in dry particulates exiting the spray dryer and their subsequent capture in a particulate collector following the spray dryer. The particulates captured in the collector are discharged as a dry material and the cleaned flue gases pass through the filter to the stack (fig 10-1a).

n. *Dry, post furnace limestone injection.* Ground dry limestone is injected directly into the flue gas duct prior to a fabric filter. The limestone reacts in the hot medium with the SO_2 contained in the combustion gases and is deposited on the filter bags as sodium sulfate and sodium sulfite. The dry particulate matter is then discharged to disposal and the cleaned flue gases pass through the filter medium to the stack (fig 10-1b).

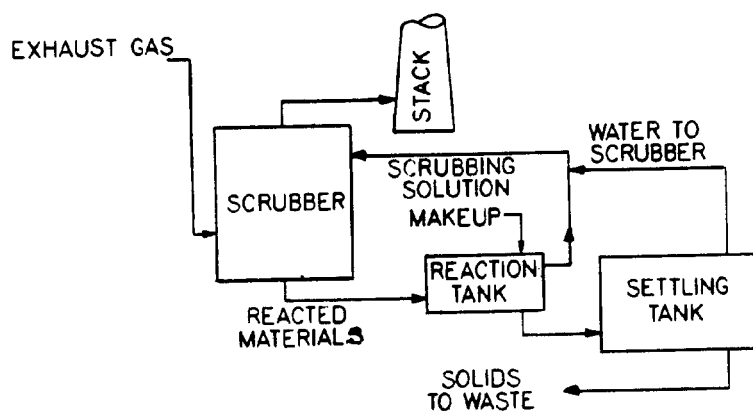
o. *Dry furnace injection of limestone.* In this system, dry ground limestone is injected into the boiler where it is calcined and reacts with the SO_2 formed during combustion of the fuel. The flue gases containing the sodium sulfate, sodium sulfite, unreacted limestone, and fly ash all exit the boiler together and are captured on a particulate collector. The cleaned flue gases pass through the filter medium and out through the stack (fig 10-1a).

p. *Magnesium oxide (MgO) scrubber.* This is a regenerative system with recovery of the reactant and sulfuric acid. As can be seen in figure 10-2 the flue gas must be precleaned of particulate before it is sent to the scrubber. An ESP or venturi scrubber can be used to remove the particulate. The flue gas then goes to the MgO scrubber where the principal reaction takes place between the MgO and SO_2 to form hydrated magnesium sulfite. Unreacted slurry is recirculated to the scrubber where it combines with makeup MgO and water and liquor from the slurry dewatering system. The reacted slurry is sent through the dewatering system where it is dried and then passed through a recovery process, the main step of which is calcination. High reliability of this system has not yet been obtained. SO_2 removal efficiencies can be high, but scaling and corrosion are major problems.

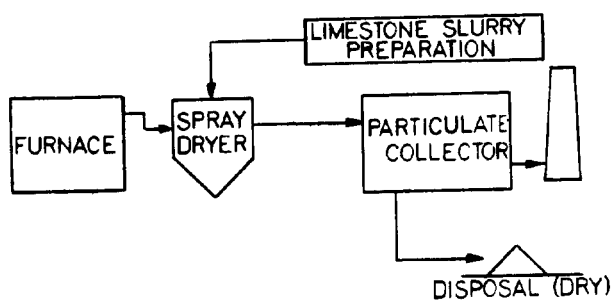
q. *Wellman Lord process.* Sodium sulfite is the scrubbing solution. It captures the SO_2 to produce sodium bisulfite, which is later heated to evolve SO_2 and regenerate the sulfite scrubbing material. The SO_2 rich product stream can be compressed or liquified and oxidized to sulfuric acid, or reduced to sulfur. Scaling and plugging are minimal problems because the sodium compounds are highly soluble in water. A Wellman-Lord unit has demonstrated an SO_2 removal efficiency of greater than 90 percent and an availability of over 85 percent. The harsh acid environment of the system has caused some mechanical problems (See figure 10-3).

r. *Catalytic oxidation.* The catalytic oxidation process uses a high temperature (850 degrees Fahrenheit) and a catalyst (vanadium pentoxide) to convert SO_2 to SO_3 . The heated flue gas then passes through a gas heat exchanger for heat recovery and vapor condensation. Water vapor condenses in the heat exchanger and combines with SO_3 to form sulfuric acid. The acid mist is then separated from the gas in an absorbing tower. The flue gas must be precleaned by a highly efficient particulate removal device such as an electrostatic precipitator preceding the cat-ox system to avoid poisoning the catalyst. The major drawback of this system is that it cannot be economically retro-fitted to existing installations (fig 10-4).

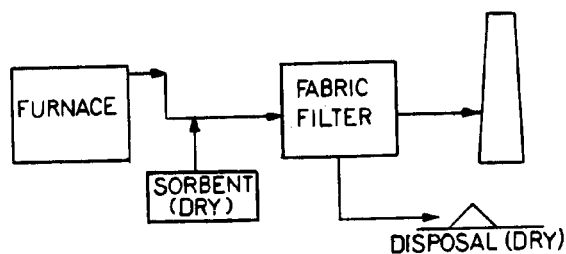
s. *Single alkali sodium carbonate scrubbing.* In order to eliminate the plugging and scaling problems associated with direct calcium scrubbing, this FGD system was developed. As shown in figure 10-5, the process is a once through process involving scrubbing



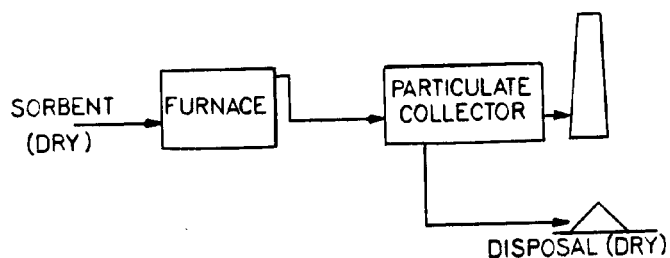
10-1



10-1 (a)



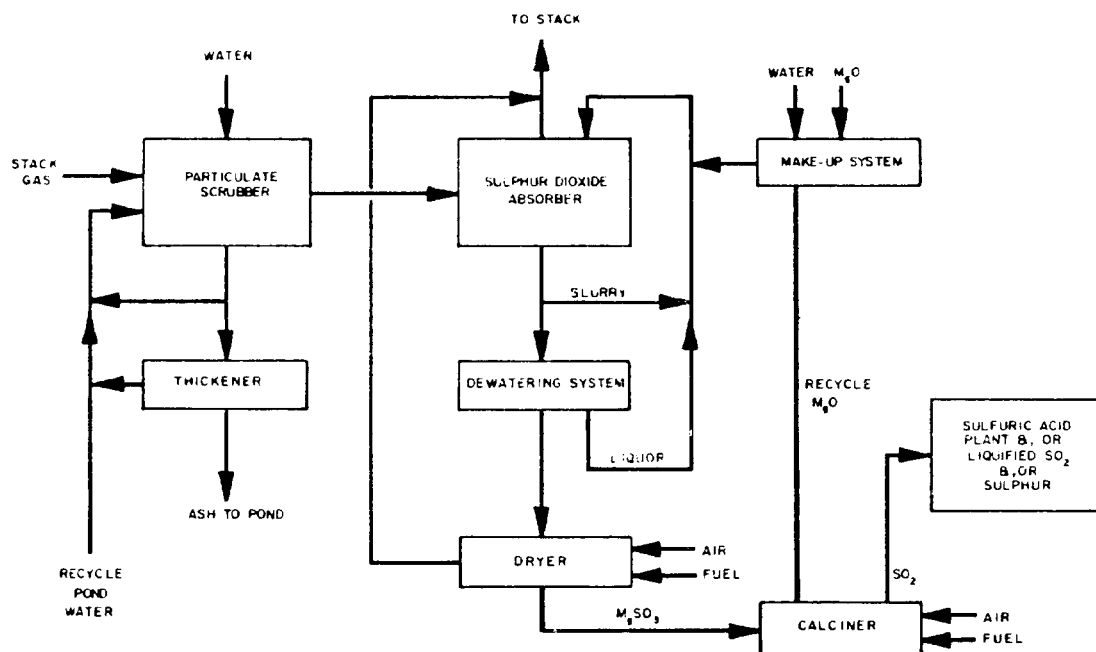
10-1 (b)



10-1 (c)

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Figure 10-1. Lime (limestone) injection system schematic



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Figure 10-2. Magnesia slurry SO_2 recovery process

with a solution of sodium carbonate or sodium hydroxide to produce a solution of dissolved sodium sulfur salts. The solution is then oxidized to produce a neutral solution of sodium sulfate. Because it is a throwaway process, the cost of chemicals make it an unattractive SO_x removal process when burning high sulfur fuels (greater than 1 percent).

t. Dual alkali sodium scrubbing.

- (1) The dual alkali SO_x removal system is a regenerative process designed for disposal of wastes in a solid/slurry form. As shown in figure 10-6, the process consists of three basic steps; gas scrubbing, a reactor system, and solids dewatering. The scrubbing system utilizes a sodium hydroxide and sodium sulfite solution. Upon absorption of SO_2 in the scrubber, a solution of sodium bisulfite and sodium sulfite is produced. The scrubber effluent containing the dissolved sodium salts is reacted outside the scrubber with lime or limestone to produce a precipitate of calcium salts containing calcium sulfate. The precipitate slurry from the reactor system is dewatered and the solids are disposed of in a landfill. The liquid fraction containing soluble salts is recirculated to the absorber. Double alkali systems can achieve efficiencies of 90 - 95% and close to 100% reagent utilization.

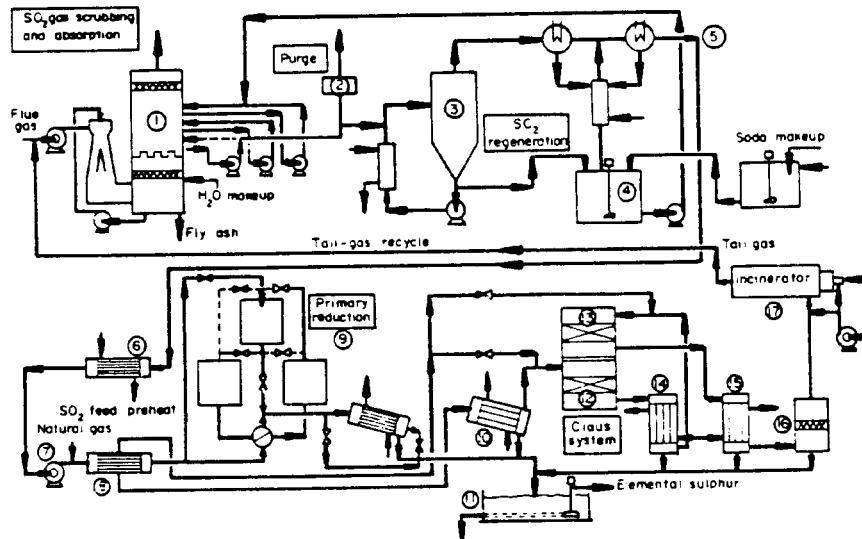
- (2) This system is designed to overcome the inherent difficulties of direct calcium slurry scrubbing. All precipitation occurs outside the

scrubber under controlled reactor conditions. The principal advantages of the dual alkali system are:

- (a) Scaling problems associated with direct calcium-based scrubbing processes are significantly reduced.
- (b) A less expensive calcium base can be used.
- (c) Due to high solubility and concentration of active chemicals, lower liquid volumes can be used thereby lowering equipment costs.
- (d) Slurries are eliminated from the absorption loop, thereby reducing plugging and erosion problems.
- (e) A sludge waste, rather than a liquid waste, is produced for disposal.
- (f) High SO_2 removal efficiency (90% or more).

u. Absorption of SO_2 .

- (1) Activated carbon has been used as an absorbent for flue-gas desulfurization. Activated carbon affects a catalytic oxidation of SO_2 to SO_3 , the latter having a critical temperature of 425 degrees Fahrenheit. This allows absorption to take place at operating temperatures. The carbon is subsequently regenerated in a separate reactor to yield a waste which is used in the production of high grade sulfuric acid, and the regenerated absorbent. There are serious problems involved in the regeneration of the absorbent, including carbon losses due



- | | |
|------------------------------|--------------------------------|
| 1) ABSORBER | 9) CATALYTIC REDUCTION SECTION |
| 2) SURGE TANK | 10) COOLER |
| 3) REGENERATION SECTION | 11) SULPHUR HOLDING PIT |
| 4) DISSOLVING TANK | 12, 13) CLAUSS CONVERTER |
| 5) CONCENTRATED SO DISCHARGE | 14, 15) CONDENSORS |
| 6) PREHEATER | 16) COALESCER |
| 7) NATURAL GAS ADDITION | 17) INCINERATOR |
| 8) HEATER | |

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Figure 10-3. Wellman-Lord SO₂ reduction system

to attrition, chemical decomposition, serious corrosion problems, and danger of combustion of the reactivated carbon.

- (2) Zeolites are a class of highly structured aluminum silicate compounds. Because of the regular pore size of zeolites, molecules of less than a certain critical size may be incorporated into the structure, while those greater are excluded. It is often possible to specify a certain zeolite for the separation of a particular material. Zeolites possess properties of attrition resistance, temperature stability, inertness to regeneration techniques, and uniform pore size which make them ideal absorbents. However, they lack the ability to catalyze the oxidation of SO₂ to SO₃ and thus cannot desulfurize flue-gases at normal operating temperatures. Promising research is under way on the development of a zeolite material that will absorb SO₂ at flue-gas temperatures by oxidation of SO₃ and

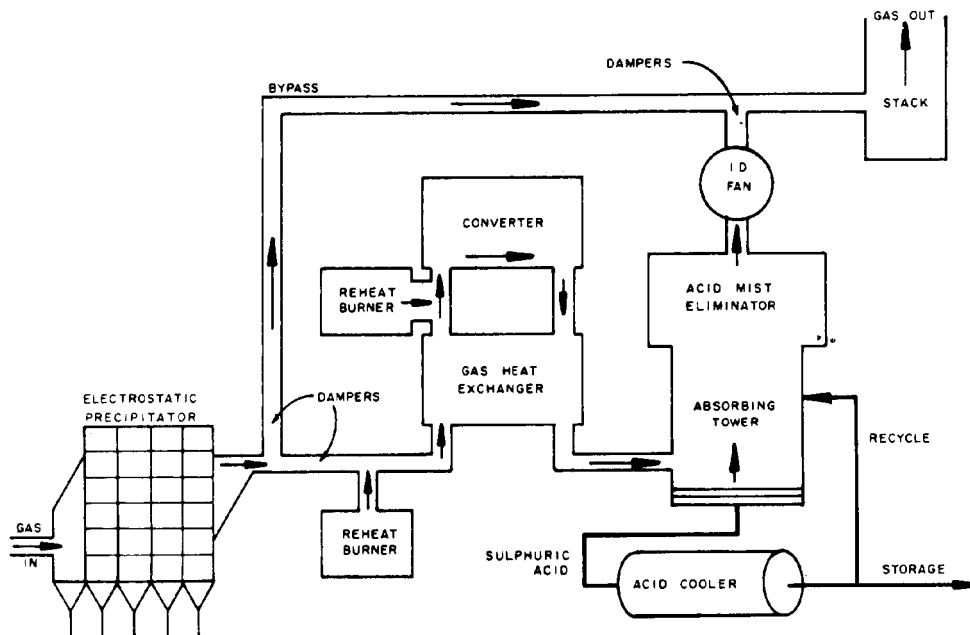
subsequently store it as a sulphate in the pores of the zeolite.

v. *Cost of flue-gas desulfurization.* The actual capital and operating costs for any specific installation are a function of a number of factors quite specific to the plant and include:

- Plant size, age, configuration, and locations,
- Sulfur content of the fuel and emission control requirements,
- Local construction costs, plant labor costs, and cost for chemicals, water, waste disposal, etc.,
- Type of FGD system and required equipment,
- Whether simultaneous particulate emission reduction is required.

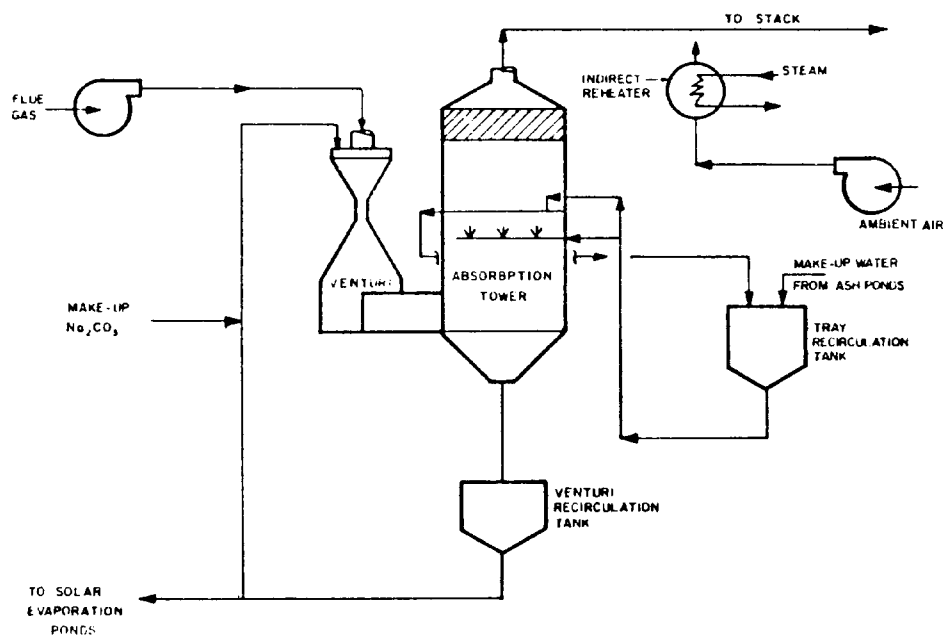
10-3. Procedure to minimize SO_x emission

a. *Efficiency requirement.* The SO_x removal efficiency necessary for any given installation is dependent upon the strictest regulation governing that installation. Given a certain required efficiency, a choice can be



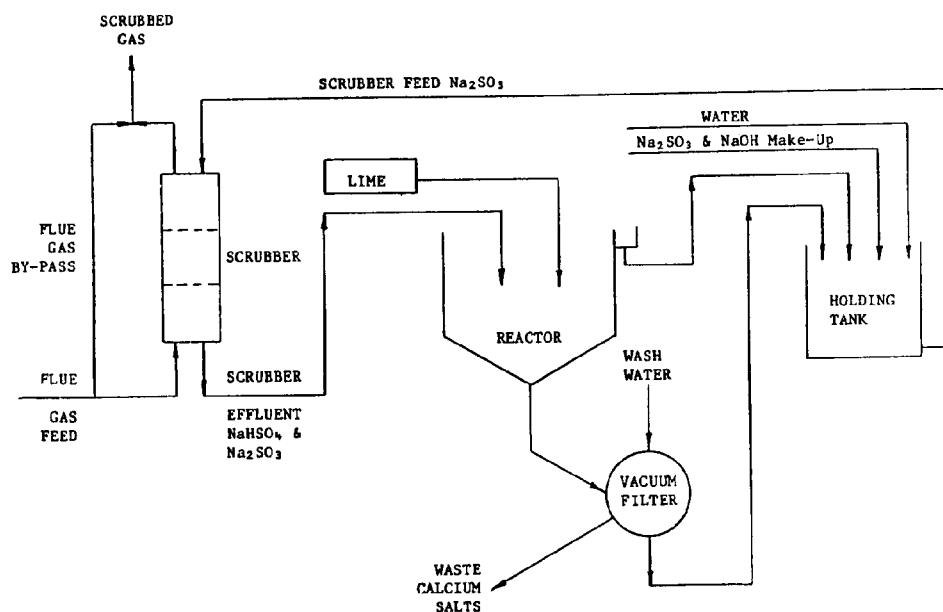
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Figure 10-4. Catalytic oxidation system



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Figure 10-5. Single alkali sodium carbonate scrubber



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Figure 10-6. Dual alkali system

made among the different reduction techniques. This section shows how a rational basis can be utilized to determine the best method.

b. Boiler modification. This technique is useful in reducing SO_x emissions by 0 to 6% depending upon the boiler. For industrial boilers operating above 20% excess-air the use of proper control equipment or low excess-air combustion will usually reduce emissions by 4 to 5%. If the operating engineer is not familiar with boiler optimization methods, consultants should be utilized.

c. Fuel substitution. This method can be used for almost any percent reduction necessary. Availability and cost of the fuel are the major factors to be considered. Fuels can be blended to produce the desired sulfur input. Care must be taken, however, so that the ash produced by the blending does not adversely affect the boiler by lowering the ash fusion temperature or causing increased fouling in the convection banks.

d. Flue-gas desulfurization. Various systems are available for flue-gas desulfurization. Some of these systems have demonstrated long term reliability of operation with high SO_x removal efficiency. Lime/limestone injection and scrubbing systems have been most frequently used. It must be recognized that each boiler control situation must be accommodated in the overall system design if the most appropriate system is to be installed. The selection and design of such a control system should include the following considerations:

- (1) Local SO_2 and particulate emission requirements, both present and future,
- (2) Local liquid and solid waste disposal regulations,

- (3) Local market demand for recovered sulfur,
- (4) Plant design limitations and site characteristics,
- (5) Local cost and availability of chemicals, utilities, fuels, etc.,
- (6) Added energy costs due to process pumps, reheaters, booster fans, etc.

10-4. Sample problems.

The following problems have been provided to illustrate how to determine the maximum fuel sulfur content allowable to limit SO emission to any particular level.

a. Approximately 90 to 97 percent of fuel sulfur is oxidized to sulfur dioxide (SO_2) during combustion. This means that for every lb of sulfur in the fuel, approximately 2 lbs of sulfur oxides will appear in the stack gases. (The atomic weight of oxygen is $\frac{1}{2}$ that of sulfur.) Since most of the sulfur oxides are in the form of SO_2 , emissions regulations are defined in these units. To estimate maximum probable SO_2 emissions, the following equation applies:

$$\frac{\text{lbs SO}_2}{\text{MMBtu}} = \frac{2 \times \% \text{ Sulfur by Weight in Fuel}}{\text{Fuel Heating Value (Btu/lb)}} \times 10^4 \quad (\text{eq. 10-1})$$

b. Assume a fuel-oil burning boiler must limit emissions to .35 lbs/MMBtu. What is the maximum allowable sulfur content if No.6 Residual fuel-oil is to be used?

- (1) From table 10-3, Typical Analysis of Fuel-Oil Types, an average heating value of 18,300

Btu/lb for No.6 residual fuel has been assumed. Maximum allowable sulfur content is determined as:

$$\begin{aligned} & \frac{.35 \text{ lbs SO}_2}{\text{MMBtu}} \\ &= \frac{2 \times \% \text{ Sulfur by Weight in Fuel}}{18,300 \text{ Btu}} \times 10^4 \\ & \% \text{ Sulfur} = \frac{(.35)(18,300)}{2 \times 10^4} = .32\% \end{aligned}$$

- (2) Table 10-3 shows that No.5 and No.6 fuel oils have fuel sulfur contents in excess of .32%. If No.4 fuel oil is chosen, a fuel with less than .32% sulfur may be available.

c. Assume a fuel-oil burning boiler must limit SO_x emission to .65 lbs/MMBtu. If No.6 residual fuel oil is to be used, can SO_x emission limits be met?

- (1) From table 10-3, the minimum sulfur content in No.6 fuel oil is .7%. If .7% sulfur fuel can be purchased, the heating value of the fuel must be:

$$\begin{aligned} \text{a) } .65 \frac{\text{lb SO}_2}{\text{MMBtu}} &= \frac{2 \times .7\% \text{ Sulfur}}{\text{H. Value}} \times 10^4 \\ \text{b) Heating Value} &= 21,538 \text{ Btu/lb} \end{aligned}$$

- (2) Since the heating value of No. 6 fuel oil is generally between 17,410 and 18,990 Btu/lb, SO_x emission limits cannot be met using this fuel. If we assume a No.6 fuel-oil with one percent sulfur and a heating value of 18,600 Btu/lb is used the percent SO_x removal efficiency that will be required is determined as:

$$\text{a) } \frac{\text{lbs SO}_2 \text{ emissions}}{\text{MMBtu}} = \frac{2 \times 1\% \text{ Sulfur}}{18,600 \text{ Btu/lb}} \times 10^4 = 1.08$$

$$\text{b) } \frac{1.08 - .65}{1.08} = 40\% \text{ removal of SO}_2 \text{ required}$$

d. Assume a boiler installation burns No.4 fuel-oil with a heating value of 19,000 Btu/lb. What is the maximum fuel sulfur content allowable to limit SO_x emissions to .8 lbs/MMBtu?

$$\begin{aligned} (1) \quad .80 \frac{(\text{lbs SO}_2)}{\text{Mil Btu}} &= \frac{2 \times \% \text{ Fuel Sulfur}}{19,000 \text{ Btu/lb}} \times 10^4 \\ (2) \quad \% \text{ Fuel Sulfur} &= \frac{.80 (19,000)}{2 \times 10^4} \\ &= .76\% \end{aligned}$$

e. Assume a coal burning boiler must limit SO_x emissions to 1 lb/MMBtu. If sub-bituminous coal with a heating value of 12,000 to 12,500 Btu/lb (see table 10-4) is to be used what is the maximum allowable fuel sulfur content?

$$\begin{aligned} (1) \quad \frac{(1.0 \text{ lbs SO}_2)}{\text{MMBtu}} &= \frac{2 \times \% \text{ Fuel Sulfur}}{12,000 \text{ Btu/lb}} \times 10,000 \\ (2) \quad \% \text{ Fuel Sulfur} &= \frac{1.0 (12,000)}{2 \times 10,000} \\ &= .60\% \end{aligned}$$

f. Since coal of this low sulfur content is not available, what SO_x removal efficiency would be required burning 1% sulfur coal?

$$\begin{aligned} (1) \quad \text{Estimated SO}_2 \text{ emissions} \frac{\text{lbs}}{\text{MMBtu}} &= \frac{2 \times 1\%}{12,000} \times 10^4 \\ &= \frac{1.67 \text{ lbs SO}_2}{\text{Mil Btu}} \\ (2) \quad \% \text{ Removal Efficiency} &= \frac{1.66 - 1.0}{1.66} \\ &= 40\% \end{aligned}$$

TABLE 10-3
TYPICAL ANALYSIS OF FUEL OIL TYPES

Grade of Fuel Oil	No. 1	No. 2	No. 4	No. 5	No. 6
Weight, percent					
Sulfur	0.01-0.5	0.05-1.0	0.2-2.0	0.5-3.0	0.7-3.5
Hydrogen	12.3-14.5	11.8-13.9	(10.6-13.0)	(10.5-12.0)	(86.5-90.2)
Carbon	85.9-86.7	86.1-88.2	(86.5-89.2)	(86.5-89.2)	(86.5-90.2)
Nitrogen	Nil-0.1	Nil-0.1	-	-	-
Oxygen	-	-	-	-	-
Ash	-	-	0-0.1	0-0.1	0.01-0.5
Gravity					
Deg API	40-44	28-40	15-30	14-22	7-22
Specific	0.825-0.806	0.887-0.825	0.996-0.876	0.972-0.922	1.022-0.922
Lb per gal	6.87-6.71	7.39-6.87	8.04-7.30	8.10-7.68	8.51-7.68
Pour point, F	0 to -50	0 to -40	-10 to +50	-10 to +80	+15 to +85
Viscosity					
Centistokes at 100°F	1.4-2.2	1.9-3.0	10.5-65	65-200	260-750
SUS at 100°F	-	32-38	60-300	-	-
SSF at 122°F	-	-	-	20-40	45-300
Water and Sediment, Vol%	-	0-0.1	tr-1.0	0.05-1.0	0.05-2.0
Heating Value					
Btu, per lb, gross	19,670-19,860	19,170-19,750	18,280-19,400	18,100-19,020	17,410-18,990

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TABLE 10-3

TYPICAL ANALYSIS OF FUEL OIL TYPES

Grade of Fuel Oil	No. 1	No. 2	No. 4	No. 5	No. 6
Weight, percent					
Sulfur	0.01-0.5	0.05-1.0	0.2-2.0	0.5-3.0	0.7-3.5
Hydrogen	12.3-14.5	11.8-13.9	(10.6-13.0)	(10.5-12.0)	(86.5-90.2)
Carbon	85.9-86.7	86.1-88.2	(86.5-89.2)	(86.5-89.2)	(86.5-90.2)
Nitrogen	Nil-0.1	Nil-0.1	-	-	-
Oxygen	-	-	-	-	-
Ash	-	-	0-0.1	0-0.1	0.01-0.5
Gravity					
Deg API	40-44	28-40	15-30	14-22	7-22
Specific	0.825-0.806	0.887-0.825	0.996-0.876	0.972-0.922	1.022-0.922
Lb per gal	6.87-6.71	7.39-6.87	8.04-7.30	8.10-7.68	8.51-7.68
Pour point, F	0 to -50	0 to -40	-10 to +50	-10 to +80	+15 to +85
Viscosity					
Centistokes at 100°F	1.4-2.2	1.9-3.0	10.5-65	65-200	260-750
SUS at 100°F	-	32-38	60-300	-	-
SSF at 122°F	-	-	-	20-40	45-300
Water and Sediment, Vol%	-	0-0.1	tr-1.0	0.05-1.0	0.05-2.0
Heating Value					
Btu, per lb, gross	19,670-19,860	19,170-19,750	18,280-19,400	18,100-19,020	17,410-18,990

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